PEREGRINE ENERGY LTD.

2004 Annual Report

Corporate Profile

Peregrine Energy Ltd. ("Peregrine"), formerly Tesoro Energy Corp., is a Calgary, Alberta based junior oil and gas company engaged in the exploration for and production of oil and natural gas in Western Canada.

On July 21, 2004, Tesoro Energy Corp. ("Tesoro") announced the successful completion of its previously announced business combination with Peregrine Energy Ltd. ("Privateco"). Under the terms of the amalgamation each Tesoro and Privateco shareholder received one share of the amalgamated company for each 20 shares held of the predecessor companies. The new combined company continued to carry on business under the name "Peregrine Energy Ltd.".

Production for the fourth quarter of 2004 averaged 1,566 boepd with capability at year end of approximately 1,850 boepd.

The Company has an extensive inventory of development and exploratory opportunities ranging from low-risk, long-life shallow gas projects to high-impact exploratory projects in the Gunnell, Noel, Jackpine Creek and Buick Creek regions of Northeast B.C.

Peregrine Energy Ltd. trades on the Toronto Stock Exchange under the symbol "PEG".

Annual Meeting

Peregrine invites shareholders and other interested parties to attend its Annual General Meeting on May 26, 2005 at 10:00 a.m. in the Plaza Room of The Metropolitan Conference Centre, located at 333 – 4th Avenue S.W., Calgary, Alberta.

Shareholders not attending the meeting are encouraged to complete the form of proxy mailed with this report and return it at their earliest convenience.

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Financial & Operating Highlights

Year Ended December 31,	2004 (Audited)	2003* (Audited)
FINANCIAL		
Oil and gas production revenue	$ 11,297,904	$ 2,282,632
Cash flow from operations[1]	$ 3,710,391	$ 702,381
Cash flow per share – basic and diluted[1]	$ 0.19	$ 0.17
Net income	$ 4,132,473	$ 500,050
Earnings per share – basic and diluted	$ 0.21	$ 0.12
Capital expenditures, net of dispositions	$ 56,113,392	$ 765,334
Debt	$ 19,200,000	$ 1,275,000
Shareholders' equity	$ 47,457,176	$ 11,854,180
Common shares outstanding, end of period	30,124,379	9,719,925*

*shares and amounts per share have been adjusted by a 1 to 20 exchange ratio

OPERATING		
Average daily production		
Crude oil and NGL's (bopd)	439	104
Natural gas (mcfpd)	1,606	343
Barrel of oil equivalent (boepd @ 6:1)	707	161
Average Selling Prices		
Crude oil and NGL's ($/bbl)	$ 46.46	$ 38.83
Natural gas ($/mcf)	$ 6.51	$ 6.51
Barrel of oil equivalent ($/boe @ 6:1)	$ 43.67	$ 38.84
Average Field Netback ($/boe @ 6:1)	$ 22.37	$ 20.50

[1] Cash flow from operations and cash flow per share are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). Cash flow from operations is calculated by taking net earnings and adding back noncash balances such as depletion and depreciation, accretion, gain on sale of investments, and stock based compensation expense. Management believes that cash flow is a useful supplemental measure to analyze operating performance and provide an indication of the results generated by the Company's principal business activities. Peregrine's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

FORWARD LOOKING STATEMENTS

Except for historical financial information contained herein, the matters discussed in this document may be considered forward-looking statements. Such statements include declarations regarding management's intent, belief or current expectations. Prospective investors are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties; actual results could differ materially from those indicated by such forward-looking statements. Among the important factors that could cause actual results to differ materially from those indicated by such forward-looking statements are: (i) that the information is of a preliminary nature and may be subject to further adjustment, (ii) the possible unavailability of financing, (iii) risks related to the exploration and development of oil and gas properties, (iv) the impact of price fluctuations and the demand and pricing for oil and natural gas, (v) the seasonal nature of the business, (vi) start-up risks, (vii) general operating risks, (viii) dependence on third parties, (ix) changes in government regulation, (x) the effects of competition, (xi) dependence on senior management, (xii) impact of the Canadian economic conditions, and (xiv) fluctuations in currency exchange rates and interest rates.

LETTER TO SHAREHOLDERS

LAST YEAR WAS THE MOST ACTIVE YEAR in the history of the Company. At the start of 2004, the Company laid out certain clearly defined mandates in order to add further value for shareholders. I am pleased to report that all the mandates were achieved. Highlights for the year include:

- Raising $22 million by way of a private placement of special warrants and flow-through shares.
- Participating in a 740 sq km 3D and 240 km 2D seismic program in the Gunnell region of N.E. British Columbia. The Company has proprietary ownership in this seismic.
- Concluding an important business transaction with a large U.S. independent producer on the Company's Gunnell Prospect.
- The business combination with Tesoro Energy Corp. and Peregrine Energy Ltd. was completed in July 2004.
- Successfully closing three asset acquisitions for an aggregate consideration of $29.5 million adding approximately 1,030 boepd and 2,837 Mboe of total proved plus probable reserves.
- Completing a 64 well shallow gas development program at Jenner, Alberta.
- Exiting 2004 at approximately 1,850 boepd compared to about 130 boepd for the prior year.

The efforts put forth and results achieved in 2004 have laid a solid foundation for continued growth in 2005 and beyond. Last year, growth was achieved primarily by way of acquisitions and shallow gas development. The asset acquisitions not only added production and reserves of approximately 1,030 boepd and 2,837 Mboe of total proved plus probable reserves but also a significant inventory of drilling and re-completion opportunities. The shallow gas development programs conducted at Jenner and Taber comprised 42 net wells and added significant long life reserves with further shallow gas development upside at Jenner and Burstall.

Also, the Company concluded its 740 sq km 3D and 240 km 2D seismic program in the Gunnell region of N.E. British Columbia last winter. In addition, Peregrine leveraged this shoot into an exploration alliance with a large U.S. independent producer in which they contributed approximately 83 sections of land underlying the seismic coverage to the joint venture. The primary targets of interest in the Gunnell area are the high deliverability Slave Point and Keg River formations. The Company has identified a significant number of drilling opportunities and has programmed up to two exploratory wells in 2005. In addition, Peregrine is pursuing several opportunities that would significantly increase its working interest in this project.

Unlike 2004 where production and reserves growth was mostly as a result of acquisitions, 2005 will see a significant shift to growth by the drill bit. However, management will continue to evaluate accretive and synergistic acquisition opportunities as they arise. The Company's capital program for 2005 has approximately $10 MM directed to exploration activities primarily in N.E. British Columbia. Approximately $10 MM is mostly geared to development drilling opportunities in Alberta and S.E. Saskatchewan. Peregrine commenced its 2005 capital program with three successful horizontal wells in S.E. Saskatchewan resulting in an initial net aggregate production rate of approximately 200 barrels per day. The Company has programmed up to five follow-up horizontal wells for this area beginning in June.

In N.E. British Columbia, Peregrine recently cased two exploratory wells, a 2,800 meter test at Jackpine Creek and a 1,700 meter test at Buick Creek, both indicating multi-zone gas potential. The Company has an average working interest of 60% in these two wells. Due to an early spring break-up, completion operations have been delayed until June, however, based on indications to date, Peregrine has budgeted follow-up wells at Buick Creek and Jackpine Creek with the first well expected to spud in Q3 . The Company has additional undeveloped lands surrounding these two wells and depending on the results from the next round of drilling, a significant development opportunity on both properties could emerge.

The 2005 capital program also includes 17 development wells at Jenner, two wells in the central Alberta region, three wells in southern Alberta, two exploratory wells at Parkbeg, Saskatchewan and a significant number of recompletion opportunities. In addition to this activity, Peregrine has budgeted for seismic programs at Swan Hills and Parkbeg and a number of strategic Crown land sales.

Depending on the degree of success attained from the Company's 2005 exploration drilling program, specifically in N.E. British Columbia, the potential for significant uplift in reserves and production capability from current levels could be realized by year end.

I would like to express my gratitude to the Board for their counsel and continued confidence in and support of the management team. Also, on behalf of the Board and Management I would like to express our sincere appreciation to our support staff, consultants and field operators for their dedication and hard work, and to our shareholders for their continued support.

Respectfully submitted on behalf of the Board.

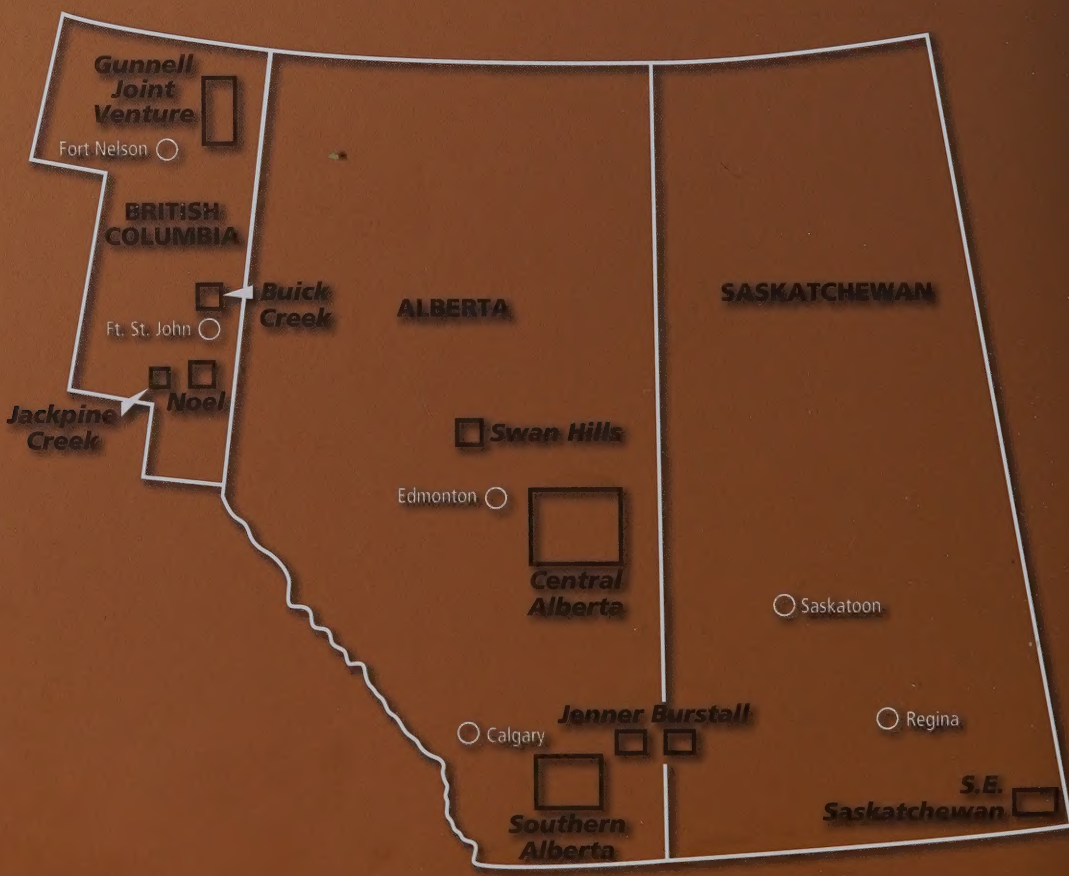
Peter Malenica

PETER MALENICA
President and Director
March 31, 2005

OPERATING AREAS

Peregrine operates in all three Western Canadian provinces. The Company's primary focus areas are Southern Alberta, Central Alberta, N.E. British Columbia and S.E. Saskatchewan. The Company operates approximately 64 percent of its total producing capability, split 62 percent oil and liquids and 38 percent natural gas.

Operations and Development Review



Southern Alberta

Currently this is the Company's largest producing region, contributing approximately 30 percent of its total production. The primary producing properties include Enchant, Grand Forks, Taber/Fincastle, Hays, Jenner, Retlaw and Long Coulee. A recent 10 well Second White Specks drilling program at Taber/Fincastle added a net 60 boepd of gas production. Of significant importance is the Company's 100 percent ownership in the Grand Forks oil producing property. The Company has identified up to 700 Mbbl of additional proven undeveloped plus probable reserves in the Upper Mannville formation. Plans are to drill four wells and implement a pressure maintenance scheme to develop these reserves. The Company is also planning to drill three exploration wells and one development well targeting the Sawtooth formation in the Grand Forks field.

Central Alberta

The Central Alberta region consists of significant producing assets in the Elk Island/Tofield, Skaro, Viking, Wood River and Killam fields. Production is primarily from reservoirs of Upper and Lower Cretaceous age. Peregrine is actively pursuing farm-in deals and land sales to build on its current land base and increase production in these areas. In the fall of 2004, Peregrine purchased a working interest in a large Glauconite oil channel in the Killam area on which up to nine infill drilling locations have been identified by 3D seismic.

Northern Alberta and N.E. British Columbia

The Northern region includes producing assets in the Noel, Shekilie, Grande Prairie and Rigel fields. The Noel property is part of the Cutbank Block development region with deep gas in multi-zone horizons. The main production comes from early and late Cretaceous zones of the Cadomin, Gething, Bluesky, Fahler, Cadotte, Paddy and Doe Creek formations. Peregrine purchased this property in September 2004 as part of a larger asset acquisition and has identified 14 low to medium risk drilling locations and eight recompletions. The target reservoirs are typically long life deep basin gas zones with initial rates ranging from 1 to 4 MMcfpd. The Company currently owns up to 50% working interest in 55 sections of land in the immediate area.

Shallow Gas Properties

The Company's shallow gas holdings are located at Jenner, Alberta and Burstall, Saskatchewan. At Jenner, Peregrine has an additional 17 infill locations planned in 2005 on the heels of last fall's successful 45 well drilling program. In addition, Peregrine is currently attempting to acquire additional lands in the area. At the Burstall shallow gas project, just east of Jenner, Peregrine has identified over 90 potential development locations. These shallow gas projects all add long life reserves and a stable production base.

S.E. Saskatchewan

The S.E. Saskatchewan area consists of significant producing assets in the Wordsworth, Kisbey/Clarilaw, Ingoldsby and Lightning fields from reservoirs of Upper Mississippian age. Currently about 25% of the entire company production comes from this area. Within Peregrine's prospect inventory, up to 20 additional wells have been identified with further drilling to commence in the third and fourth quarters of 2005. Several recompletion and workover opportunities have been identified and will be ongoing throughout 2005 to optimize and potentially increase current production and reserves.

EXPLORATION ACTIVITIES

Gunnell

In 2004, Peregrine acquired proprietary ownership rights in a $36,000,000 seismic program in the Gunnell area of N.E. British Columbia by participating for 30% interest with an oil and gas industry "major". The Gunnell seismic program, comprising 740 sq km of 3D and 240 km of 2D, was completed in April 2004. In July 2004, Peregrine leveraged this seismic shoot into an exploration alliance with a large U.S. independent producer.

The key terms of the joint venture agreement are:

- a five year term;
- Peregrine received an upfront payment (net of expenses) of $2,652,000;
- the joint venture partner contributed approximately 83 sections of land to the joint venture;
- Peregrine receives a 15% gross overriding royalty on its joint venture partner's share of production capped at $9.0 million; and
- pursuant to the Reciprocal Rights Clause in the Agreement, Peregrine has the right to propose the drilling of a well or wells. This clause gives Peregrine the ability to be pro-active on this high impact opportunity.

Primary zones of interest are the Devonian reef build-ups of the Keg River and Slave Point formations. Shallower potential exists in the Jean Marie, Mississippian, Triassic and Cretaceous zones. Peregrine plans to drill up to two 2,400 meter test wells for the reef targets of the Keg River and Slave Point formations. Earlier plans were to drill two wells with an average working interest of between 10 to 25 percent. However, Peregrine is pursuing several opportunities that would significantly increase its working interest in this project. To date the Company has identified six potential drill locations at Gunnell and it is believed that additional opportunities will present themselves with further evaluation of the seismic coverage and successful drilling results.

Swan Hills

Peregrine recently purchased 15 sections of land resulting in a 100% working interest in 31 sections in the immediate area. Multi-zone potential exists in the Cretaceous formations in the Belly River, Viking, Notikewin, Bluesky and Gething with deeper targets being the Debolt, Nisku, Leduc, Beaverhill Lake, Gilwood and Granite Wash zones. Peregrine plans to shoot a 2D seismic program over the newly purchased land. After processing and evaluation, the Company plans to drill one to two wells in the fourth quarter of 2005.

Parkbeg

Peregrine currently has a 100% working interest in 25 sections of land in the Parkbeg region of south central Saskatchewan. Abundant Open Crown land is available for future land sales. This area has multi-zone potential with shallow gas resource plays in the Second White Specks and Viking as well as Belly River, Mannville, Roseray and Mississippian potential. The Company is planning to drill two exploratory wells prior to year end.

Buick Creek

At Buick Creek, British Columbia, Peregrine has an average 60% working interest in nine sections of land. The entire area is characterized by deep seated faults oriented southwest to northeast along the Hay River trend, as well as smaller shallower faults intersecting at angles of 45 and 90 degrees. These develop small anticlinal features and form saddles to give rollover effect and trap hydrocarbons in multiple Cretaceous, Triassic and Mississippian zones. Often the best production is found on or correlates with the flanks of these features. The dendritic features of the Cretaceous lowstand valley systems and deltaic complexes are also related to these highs and lows.

Hydrocarbon production occurs from several different zones in the immediate area. Peregrine recently cased a 1,700 meter test as a potential multi-zone gas well. Plans are to drill two follow up wells prior to December 31, 2005.

Jackpine Creek

Subsequent to year end, Peregrine entered into a joint venture with a third party in the Jackpine Creek area of N.E. British Columbia approximately 15 km west of the Company's Noel production area. Peregrine participated as to a 50% interest in a 2,800 meter test which was cased as a potential multi-zone gas well prior to an early spring break-up. Based on the

logs from the test well, the Company acquired a 40% interest in an additional 5,100 acres at a recent Crown land sale. The Company now has an average 42% in 11 sections of land with multi-zone high deliverability gas potential. Plans are to complete and test the well in July, and is subject to favourable test results. A follow-up well will be drilled in the fourth quarter.

LAND HOLDINGS

In 2004, the Company increased its land base through strategic asset acquisitions and the purchase of approximately 27,920 net acres of Crown lands at various sales in Alberta, Saskatchewan and British Columbia. At year end, Peregrine held an extensive inventory of undeveloped land covering approximately 82,000 net acres in Alberta, Saskatchewan and British Columbia. Subsequent to year end, the Company acquired an additional 9,600 net acres of land at Swan Hills, Alberta and 2,060 net acres at Jackpine, British Columbia.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	105,885	30,397	111,765	47,713	217,650	78,110
Saskatchewan	12,657	7,274	35,020	28,946	47,677	36,220
British Columbia	22,388	2,096	36,288	5,243	58,676	7,339
TOTAL	140,930	39,767	183,073	81,902	324,003	121,669

DRILLING ACTIVITIES

Peregrine drilled a total of 66 wells (48.8 net) during 2004, compared with two wells (0.05 net) in 2003. Six exploration wells (5.7 net) were drilled, resulting in 2.8 net productive wells and 2.9 net dry holes. Sixty development wells (43.1 net) were drilled resulting in 42.6 net productive wells and 0.5 dry holes. The Company's overall success rate was 94%.

	2004		2003	
	Gross	Net	Gross	Net
Natural gas wells	58	44.0	2	0.05
Oil wells	4	1.4	–	–
Dry holes	4	3.4	–	–
Service wells	–	–	–	–
Total wells	**66**	**48.8**	**2**	**0.05**
Success rate	94%	93%	100%	100%

OIL AND GAS RESERVES SUMMARY

The Company's oil and gas reserves as at January 1, 2005 were evaluated by Sproule Associates Ltd. ("Sproule"). Their evaluation report is prepared in accordance with National Instrument ("NI") 51-101, the new standards of disclosure for oil and gas activities as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

NI 51-101 replaces the former National Policy 2-B ("NP 2-B") and requires a higher degree of confidence in the assignment of oil and gas reserves. Under NI 51-101, proved reserves are defined to have a 90% probability that the actual reserves recovered will equal or exceed the assigned estimates compared to the previous definition of "reasonable certainty" as stipulated by NP 2-B. Also, under NI 51-101, probable reserves are defined to have a 50% probability that the actual reserves recovered will equal or exceed the assigned estimates compared to the previous definition of "likelihood of existence" in NP 2-B. Because of the more stringent requirements under NI 51-101, the industry has adopted the interpretation that the new proved plus probable (P-50) reserves represent the most "realistic" estimates of remaining recoverable reserves. The following reserves information also adopts the general industry practice of comparing the new P-50 reserves to the previous proved plus risk adjusted (50%) probable reserves, commonly referred to as "established reserves", under NP 2-B.

The following tables summarize certain information with regard to Peregrine's oil and gas reserves as evaluated by Sproule as at January 1, 2005. (Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil).

FORECAST PRICES AND COSTS

As at January 1, 2005	Light and Medium Crude Oil Gross(1)	Light and Medium Crude Oil Net(2)	Heavy Oil Gross(1)	Heavy Oil Net(2)	Natural Gas Liquids Gross(1)	Natural Gas Liquids Net(2)
	(mbbls)		(mbbls)		(mbbls)	
Proved						
Developed Producing	1,019.5	906.6	123.4	110.1	18.9	14.5
Developed Non-Producing	--	--	17.6	16.8	4.8	3.8
Undeveloped	642.2	576.6	55.5	48.6	2.7	2.0
Total Proved	1,661.7	1,483.2	196.5	175.5	26.4	20.3
Probable	1,541.8	1,310.9	113.2	102.5	14.2	10.7
Total Proved Plus Probable	3,203.5	2,794.1	309.7	278.0	40.6	31.0

	Natural Gas Gross(1)	Natural Gas Net(2)	Oil Equivalent Gross(1)	Oil Equivalent Net(2)
	(mmcf)		(mboe)	
Proved				
Developed Producing	9,615.7	8,128.1	2764.4	2,385.9
Developed Non-Producing	351.9	271.3	81.1	65.8
Undeveloped	2,427.6	2,068.5	1,105.0	972.0
Total Proved	12,395.2	10,467.9	3,950.5	3,423.7
Probable	4,986.1	4,084.0	2,500.2	2,104.8
Total Proved Plus Probable	17,381.3	14,551.9	6,450.7	5,528.4

Notes:
(1) "Gross" reserves include working interest reserves only and are before royalty deductions. Gross reserves do not include royalty interest reserves.
(2) "Net" reserves include working interest after royalty deductions plus royalty interest reserves.

RESERVES LIFE INDEX

	Q4 2004 Production	Reserves Life Index ("RLI") Total Proved	Reserves Life Index ("RLI") Proved Plus Probable
Crude Oil (bopd)	838	6.2	11.8
Natural Gas (mcfpd)	4,371	7.8	10.9
Oil Equivalent (boepd)	1,566	6.9	11.4

Note: Reserve Life index is calculated by dividing the Company interest reserve by the estimated annual production of the corresponding product category.

NET PRESENT VALUE OF RESERVES

It should not be assumed that the estimates of future net revenues presented in the following table represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE

As at December 31, 2004 Forecast Prices and Costs Before Income Taxes Discounted at (%/year) ($M)	0%	5%	10%	15%
Proved Developed Producing	50,518.7	43,398.1	38,364.0	34,616.9
Proved Developed Non-Producing	1,243.0	922.3	711.3	567.4
Proved Undeveloped	15,584.2	11,348.0	8,426.2	6,315.5
Total Proved	67,346.0	55,668.4	47,501.5	41,499.9
Probable	35,222.9	22,238.2	15,103.8	10,687.5
Total Proved Plus Probable	102,568.9	77,906.6	62,605.3	52,187.4

SPROULE JANUARY 1, 2005 ESCALATING PRICE FORECAST

The escalating crude oil and natural gas pricing, inflation factors and the exchange rate utilized in the Sproule Report are as follows:

Year	WTI Cushing US$/bbl	Edmonton Par Price 40°API Cdn$/bbl	Hardisty Bow River 24.9°API Cdn$/bbl	Cromer Medium AECO 29.3°API Cdn$/bbl	AECO C-Spot Cdn$/mmBTU	Inflation Rate %/Year	Exchange Rate US$/Cdn
2005	44.29	51.25	36.26	44.53	6.97	2.5	0.840
2006	41.60	48.03	34.89	41.87	6.66	2.5	0.840
2007	37.09	42.64	32.11	37.27	6.21	2.5	0.840
2008	33.46	38.31	30.68	33.43	5.73	2.5	0.840
2009	31.84	36.36	29.08	31.70	5.37	1.5	0.840
Thereafter various escalation rates.							

SPROULE JANUARY 1, 2005 CONSTANT PRICE FORECAST

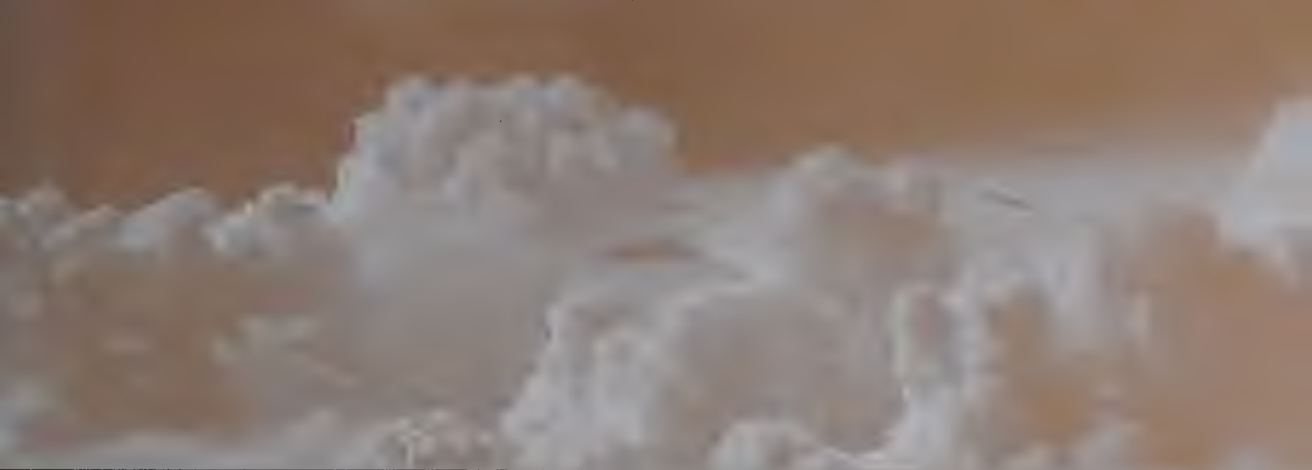
The constant crude oil and natural gas benchmark pricing and the exchange rate utilized in the Sproule Report are as follows:

Year	WTI Cushing Oklahoma US$/bbl	Edmonton Par Price 40°API Cdn$/bbl	Hardisty Bow River 24.9°API Cdn$/bbl	Cromer Medium 29.3°API Cdn$/bbl	Natural Gas AECO Gas Price Cdn$/mmBTU	Natural Gas Liquids FOB Field Gate Cdn$/bbl	Exchange Rate(1) US$/Cdn
Historical 2004	44.04	46.51	24.15	32.10	6.78	45.81	0.832

RESERVES RECONCILIATION TABLE

This reserve reconciliation reflects net company interest after royalty deductions and including royalty income.

As at December 31, 2004	Light and Medium Net Crude Oil (mbbl)	Heavy Net Crude Oil (mbbl)	Total Net Crude Oil (mbbl)	Net NGL's (mbbl)	Net Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved Producing						
Opening Balance: Dec. 31, 2003	21.9	66.8	88.7	2.3	234.0	130.0
Technical Revisions	77.4	(13.0)	64.4	3.2	1,831.3	372.8
Discoveries	11.5	0.0	11.5	0.0	3,446.0	585.8
Acquisitions	954.0	58.0	1,012.0	12.0	3,028.0	1,528.7
Economic Factors	76.5	37.1	113.6	2.2	285.1	163.3
Production	(120.8)	(12.0)	(132.8)	(3.2)	(455.0)	(211.8)
Closing Balance: Dec. 31, 2004	1,020.5	136.9	1,157.4	16.5	8,369.4	2,568.8
Total Proved						
Opening Balance: Dec. 31, 2003	21.9	66.8	88.7	2.3	234.0	130.0
Technical Revisions	(23.4)	53.1	29.7	4.9	2,247.7	409.2
Discoveries	11.5	0.0	11.5	0.0	4,880.4	824.9
Acquisitions	1,632.0	58.0	1,690.0	16.0	3,510.0	2,291.0
Economic Factors	76.4	16.5	92.9	2.0	305.2	145.8
Production	(120.8)	(12.0)	(132.8)	(3.2)	(455.0)	(211.8)
Closing Balance: Dec. 31, 2004	1,597.6	182.4	1,780.0	22.0	10,722.3	3,589.1
Proved Plus Probable						
Opening Balance: Dec. 31, 2003	32.3	95.3	127.6	3.3	302.0	181.2
Technical Revisions	517.0	76.0	593.0	10.9	3,810.5	1,239.0
Discoveries	19.9	0.0	19.9	0.0	5,946.8	1,011.0
Acquisitions	2,399.0	117.0	2,516.0	20.0	4,987.0	3,367.2
Economic Factors	94.5	16.0	110.5	2.6	410.2	181.5
Production	(120.8)	(12.0)	(132.8)	(3.2)	(455.0)	(211.8)
Closing Balance: Dec. 31, 2004	2,941.9	292.3	3,234.2	33.6	15,001.5	5,768.1



Management's Discussion and Analysis

Management's discussion and analysis (MD&A) is a review of Peregrine's 2004 financial results and should be read in conjunction with the audited financial statements and related notes for the years ended December 31, 2004 and 2003. The financial statements have been prepared in accordance with Canadian generally accepted principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Peregrine" or the "Company" refer to Peregrine Energy Ltd.

In the MD&A, reserves and production are commonly stated in barrels of equivalent (boe) on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil (boe). Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas equal to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.

Forward-looking Statements: This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly actual results may differ materially from those predicted. The forward-looking statements contained in this MD&A are as of March 21, 2005 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

On July 21, 2004, Tesoro Energy Corp. and Peregrine Energy Ltd. ("Privateco") amalgamated and continued under the name Peregrine Energy Ltd. Under the terms of the amalgamation each Tesoro and Privateco shareholder received one share of the amalgamated company for each 20 shares held of the predecessor companies. All share related amounts within this discussion, including per share amounts, number of shares, number of options and warrants outstanding, have been adjusted to reflect the share consolidation.

HIGHLIGHTS

The year ended December 2004 was the most active in the history of the Company. During the year the Company completed three asset acquisitions, a corporate acquisition and a 64 well shallow gas development program.

The combination of increased production volumes and high oil and natural gas prices enabled Peregrine to achieve record product revenues and net earnings in 2004, showing gains of 395% and 727%, respectively, over the prior year. The majority of the annual revenue gain was a result of increased production, as production increased 340% over 2003 levels. Net earnings were enhanced significantly due to the recovery of previously unrealized future tax benefits.

Net capital expenditures for field related activities totalled $26.25 million, a significant increase from the 2003 expenditure of $1.23 million. The majority of expanded fieldwork came from a seismic program in the Gunnell area in British Columbia and the completion of a 64 well shallow gas development program at Jenner, Alberta. In addition, $29.87 million was expended on asset and corporate acquisitions. All these activities were funded by cash on hand at the beginning of the year, cash flow from operations, a private placement of special warrants and flow-through shares as well as bank financing.

SELECTED ANNUAL INFORMATION

	2004	2003	2002
Petroleum and natural gas revenue	**$ 11,297,904**	$ 2,282,632	$ 2,286,084
Net earnings	**$ 4,132,473**	$ 500,050	$ 394,127
Per basic share	**$ 0.21**	$ 0.12	$ 0.12
Per diluted share	**$ 0.21**	$ 0.12	$ 0.12
Total assets	**$ 89,129,911**	$ 14,935,170	$ 3,438,152
Bank operating loan	**$ 19,200,000**	$ 275,000	–
Long-term financial liabilites	–	$ 1,000,000	$ 1,000,000

RESULTS OF OPERATION

Petroleum and natural gas revenue

Peregrine's petroleum (crude oil and natural gas liquids) and natural gas revenue increased significantly to $11,297,904 in 2004 from $2,282,632 in 2003 due to increased production and increased oil and liquids prices. The production increases were mainly due to the property and corporate acquisitions made during the year. Production volumes in 2004 increased to 707 boepd from 161 boepd in the prior year. Natural gas production increased to 1,606 mcfpd from 343 mcfpd and oil and liquids production increased to 439 bopd from 104 bopd. Production for the fourth quarter of 2004 averaged 1,566 boepd with capability at year end of approximately 1,850 bopd. The production split between oil and natural gas in the fourth quarter of 2004 was 53% oil and liquids and 47% natural gas.

Average prices (before hedging) realized from the sale of oil and NGL's increased from $38.83 per barrel in 2003 to $46.46 per barrel in 2004, and average prices realized from the sale of natural gas remained the same at $6.51 per mcf.

Peregrine's commodity price risk management policy uses forward sales, options, puts and costless collars to partially offset the effects of large price fluctuations. Hedging activities in 2004 produced a financial instrument gain of $299,418,which is composed of an unrealized gain at year end of $465,204 offset by realized losses incurred during the year of $165,786. There were no financial instrument contract in 2003. At December 31, 2004, the Company had entered into financial derivative contracts for 1,800 GJ/d at prices ranging from Cdn$6.54/GJ - Cdn$7.17/GJ, and for 93 bopd at prices ranging from US$30.62 – US$44.65. Subsequent to year end the Company locked in a costless collar for 250 bopd of oil (approximately one quarter of the Company's daily oil production) for the period May 1, 2005 to April 30, 2006 at a costless collar price of US$50.00/bbl – US$56.00/bbl.

Seismic sale

In July, 2004, the Company concluded a transaction with a large US independent producer on its Gunnell prospect whereby the Company sold a licenced copy of its seismic data for net proceeds of $2,652,000. Under the terms of the agreement further sales of this data to other parties is suspended for two years. Accordingly, revenue is deferred and recognized over the two year period. For the year ended December 31, 2004, $663,000 has been recognized in earnings.

Royalties

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include credits received through the Alberta Royalty Tax Credit ("ARTC") program. During 2004, total royalties were $1,914,871 as compared to $280,384 in 2003. This increase is due to the significant increase in production volumes. Royalties as a percentage of gross revenue (before hedging adjustments) were 17% in 2004 as compared to 12% in 2003. This increase in the royalty percentage is due to the properties acquired in 2004 carrying higher royalty burdens and not being eligible for the ARTC program.

Production expenses

Production expenses were $3,867,913 in 2004 compared with $797,379 in 2003. On a boe basis, this represented a 10% increase from $13.57 per boe in 2003 to $14.95 per boe in 2004. This increase resulted mainly from the number of one-time workovers and the repair and maintenance required to be performed on the properties purchased during the year. The majority of the workovers and repair and maintenance expenditures were performed in the fourth quarter of 2004. The Company expects that operating costs on a per boe basis will be lower in 2005 as new lower cost production is brought on and fewer workovers are performed.

Field operating netbacks

On an equivalent basis, 2004 operating net backs rose 9% to $22.37 per boe from $20.50 per boe in 2003. This increase is mainly due to product revenue increasing by 12.4%, offset by increased royalty expenses.

	2004 $/boe	2003 $/boe
Production revenue	**43.67**	38.84
Transportation	**(0.10)**	0.00
Hedging	**1.15**	0.00
Royalties	**(7.40)**	(4.77)
Production expenses	**(14.95)**	(13.57)
Field operating net back	**22.37**	20.50

General and administrative

General and administrative expense ("G&A") increased from $383,569 in 2003 to $1,659,261 in 2004. The increase in G&A reflects expenses incurred as the Company increased in size, raised equity, and positioned itself for growth in the future. G&A costs in 2004 also include a non-cash compensation expense in the amount of $458,706 (2003 - nil) related to stock options issued. On a unit of production basis, G&A was $6.41 per boe in 2004 as compared to $6.52 per boe in 2003. On a go forward basis, as the majority of G&A costs are fixed costs, and production levels are significantly higher as compared to the 2004 average daily rate of 707 boepd, the unit cost per boe will decrease noticeably.

Interest expense

In 2004, Peregrine incurred interest expense of $390,937 as compared to $118,919 in 2003. Included in the 2004 expenses was an amount of $55,191 (2003 - $100,000) which related to a debenture held by Keantha Holdings Inc, that paid interest at a rate of 10% per annum. This debenture was repaid in 2004. The balance of $335,746 (2003 - $18,919) is mainly interest on Peregrine's operating line of credit and unexpended flow-through expenditures. The increase in bank loan interest is due to the increased borrowings required as a result of property purchases and Peregrine's capital expenditure program.

Depletion, depreciation and accretion

Depletion and depreciation expenses in 2004 increased to $4,251,878 ($16.43 per boe) from $435,775 ($7.42 per boe) in 2003. The higher charges are due to increased production volumes and an increase in per unit charges. The large increase in per unit costs is a result of the increase in the cost of property acquisitions made throughout the year, a trend observed throughout the entire oil and gas industry. Acquisitions are made using proven plus probable reserves while the depletion calculation only uses proven reserves. The 2004 depletion calculation includes $10,086,100 of future capital expenditures to develop the Company's reserves, but excludes $20,838,821 of unproved property and related seismic costs.

Accretion expense in 2004 increased to $253,372 from $38,872 mainly due to the asset retirement obligations assumed as a result of the property acquisitions made during the year (see the discussion of asset retirement obligations on page 17).

Stock-based compensation

Effective January 1, 2004, the Company adopted the fair value method of accounting for stock options, on a retroactive basis, without prior period restatement. In the past, the Company measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the grant date, no compensation cost was recognized on any option issuance. All options vested in 2002 and there were no options granted in 2003.

As a result of the adoption of this policy, the Company has recorded a charge to retained earnings of $74,400 as at January 1, 2004 to reflect the accumulated stock option expense awards made under the plan subsequent to January 1, 2002. Of this amount, $37,200 was recorded as an increase to both share capital and contributed surplus. The estimated fair value of the options issued in 2002 has been determined using a modified Black-Scholes option pricing model assuming no dividends are paid on common shares, a risk-free interest rate of 5.5%, an average life of 5.0 years, weighted average fair value per option of $1.20 and a volatility of 55%.

As noted in the G&A discussion on page 15, the Company incurred a non-cash compensation expense in the amount of $458,706 (2003 - nil) related to stock options issued. The introduction of stock-based compensation added $1.77 per boe to the unit cost. This non-cash expense will be a recurring charge in future years as the fair value of options is amortized to expense over the option's vesting period of three years on a straight line basis. In addition, if the Company continues to grant stock options additional non-cash expenses will be incurred.

Taxes

Current income taxes were $106,233 and are composed of the Large Corporation Tax ("LCT") and the Saskatchewan Resource Surcharge. There was no current tax expense in 2003 as the Company was exempt from the LCT and held no property in Saskatchewan. It is expected that the Company's current tax expense will increase as the Company grows and continues to focus on developing its Saskatchewan properties.

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Future tax assets are only realized to the extent that their realization is considered more likely than not based upon projections of operating results and tax

planning strategies available to the Company. At December 31, 2003, the Company had $4,207,554 of unrecognized tax assets. In 2004, the Company recognized these tax assets and recorded a recovery of future income taxes in the amount of $4,257,834 as compared to $224,576 in 2003.

At December 31, 2004, the Company had a future tax liability of $3,817,271 as compared to a future tax asset of $1,032,668 at December 31, 2003. The increase is mainly due to renouncing tax benefits related to flow-through shares ($4,245,641), acquiring properties where amounts recorded for accounting purposes exceeded tax pools acquired ($4,883,834), offset by recognizing future assets which were previously unrecognized ($4,207,554).

Net earnings

Peregrine's net earnings increased to $4,132,473 in 2004 from $500,050 in 2003. This increase is mainly due to the recovery of future income taxes. Basic earnings and diluted earnings per share were $0.21 in 2004 as compared to $0.12 for basic and diluted per share amounts in the previous year.

ASSET RETIREMENT OBLIGATION

Changes to asset retirement obligations were as follows:

Balance as at January 1, 2003	$ 495,551
Liabilities incurred	2,124
Liabilities settled	(40,361)
Accretion expense	38,872
Balance as at December 31, 2003	$ 496,186
Liabilities incurred	268,707
Liabilities acquired	5,439,274
Accretion expense	253,372
Balance as at December 31, 2004	$ 6,457,539

The total future asset retirement obligations were estimated by management based on the Company's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. The undiscounted amount of estimated cash flows required to settle the obligation, adjusted for inflation, is approximately $14,650,000. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 8.5% and an inflation rate of 2%. The expected period until settlement ranges from a minimum of one year to a maximum of twenty-two years.

CAPITAL EXPENDITURES

Net investment in capital assets was $84,478,213 in 2004, as compared with $1,169,975 in 2003. The capital expenditures are summarized as follows:

	2004	2003
Drilling and development	**$ 15,231,911**	$ 228,629
Geological, geophysical and seismic	**10,345,169**	980,338
Capitalized G&A	**–**	12,087
Asset retirement obligation additions	**268,707**	404,641
Land acquisitions	**661,468**	–
Other	**15,841**	3,980
Capital expenditures	**26,523,096**	1,629,675
Acquisition of oil and gas properties	**57,961,117**	–
Disposition of oil and gas properties	**(6,000)**	(459,700)
Net capital investment	**$ 84,478,213**	$ 1,169,975

Increased geological, geophysical and seismic costs resulted mainly from Company expenditures on a seismic program in N.E. British Columbia, while the major component of drilling and development expenditures were at Jenner, Alberta where the Company completed a 64 well shallow gas development program including the construction of a 4.0 mmscfd compressor station and a six mile high pressure sales line ($9,721,032).

On July 21, 2004, Tesoro amalgamated with Peregrine Energy Ltd ("Privateco") and continued under the name Peregrine Energy Ltd. The amount of the purchase price that has been allocated to property, plant and equipment is $20,472,900 (see business combination below).

In June and September 2004, the Company purchased petroleum and natural gas properties and equipment totalling $29,498,487. In addition, an amount of $7,989,730 has been included in property and equipment to recognize the effect of the asset retirement obligation ($3,490,577) and a future income tax liability ($4,499,153) on these purchases.

BUSINESS COMBINATION

On July 21, 2004, Tesoro amalgamated with Peregrine Energy Ltd ("Privateco") and continued under the name Peregrine Energy Ltd. On the date of the amalgamation, each Tesoro and Privateco shareholder received, in exchange for twenty shares of their respective companies, one share of Peregrine. In addition, 3,000,000 warrants exercisable at $2.00 per share were also issued. As the Tesoro shareholders hold the majority of the issued shares, the amalgamation has been accounted for as an acquisition of Privateco by Tesoro using the purchase method of accounting as follows:

Net Purchase Price	
Common shares and warrants issued	$ 14,011,321
Transaction costs	380,980
Cash acquired	(14,463)
	$ 14,377,838
Allocation of purchase price	
Property and equipment	$ 20,472,900
Future income tax liabilities	(384,681)
Asset retirement obligations	(1,948,697)
Working capital deficiency	(1,911,684)
Debt	(1,850,000)
	$ 14,377,838

FINANCIAL RESOURCES AND LIQUIDITY

Peregrine relies on three sources of funding to support its capital expenditure programs:

- Internally generated cash flow provides the basic level of funding for the Company's annual capital expenditure program.
- Debt may be utilized to expand capital programs when it is deemed appropriate.
- When debt is considered to be at reasonable upper limits, new equity, if available and if on favourable terms, will be utilized to expand capital programs further.

BANK INDEBTEDNESS

The Company has authorized lines of credit of $32,500,000 with a Canadian chartered bank, comprising of a $25 million revolving operating demand loan and a $7.5 million acquisition/developmental demand loan. At December 31, 2004, bank debt was $19.2 million, an increase from the prior year amount of $275,000. This increase is mainly due to to the borrowings made to fund the September 3, 2004 property acquisiton and the completion of the 64 well shallow gas development program at Jenner, Alberta The Company, in accordance with CICA recommendations, treats the revolving demand bank debt as a current liability.

SHARE CAPITAL

On July 21, 2004, Tesoro Energy Corp. and Peregrine Energy Ltd. ("Privateco") amalgamated and continued under the name Peregrine Energy Ltd. Under the terms of the amalgamation each Tesoro and Privateco shareholder received one share of the amalgamated company for each 20 shares held of the predecessor companies. All share related amounts, including per share amounts, number of shares, number of options and warrants outstanding, have been adjusted to reflect the share consolidation.

At December 31, 2004, Peregrine had 30,124,379 shares outstanding as compared to 9,719,925 at December 31, 2003. This increase is mainly a result of the following:

- On June 3, 2004, the Company completed a public offering of 3,529,412 flow-through common shares. The expenditure commitment of $12,000,000 was renounced to investors effective December 31, 2004 in accordance with the terms of the flow-through share agreement. The related qualifying expenditure of $12,000,000 must be incurred by December 31, 2005. At December 31, 2004, $3,606,753 of expenditures have been incurred, leaving an additional $8,393,247 to be incurred in 2005.

- On December 31, 2003, the Company completed a public offering of 5,500,000 flow-through common shares. The expenditure commitment of $11,000,000 was renounced to investors effective December 31, 2003 in accordance with the terms of the flow-through share agreement. The related qualifying expenditures of $11,000,000 were incurred by December 31, 2004.

- In connection with the 2004 private placement of flow-through common shares, the Company issued Special Warrants for the purchase of 3,703,704 common shares of the Company at a price of $2.70 per share. These Special Warrants were exercised on July 21, 2004 for proceeds of $10,000,000.

- In connection with the 2002 private placement of flow-through common shares, the Company issued agents' warrants for the purchase of 16,253 common shares of the Company at a price of $1.20 per share ("Agents' Warrants"). These Agents' Warrants were exercised in 2004.

- Under the business combination described above, 12,635,881 common shares were issued to Privateco shareholders. In addition, warrants (to which no value was assigned) were issued to acquire 3,000,000 common shares at $2.00 per share. These warrants expire November 30, 2009.

- On July 21, 2004, a debenture held by Keantha Holdings, in the amount of $1,000,000, was repaid by the issuance of 370,370 common shares and $370,370 in cash.

During the year 664,375 options were granted at a weighted average exercise price of $1.87 per share. At December 31, 2004, there were 639,375 options outstanding at a weighted average price of $1.88 per share. Subsequent to year end 50,000 options were exercised at a price of $1.70 per share.

QUARTERLY RESULTS

Historical quarterly information, prepared by the Corporation in accordance with GAAP, is as follows:

Three months ended ($)	March 31	June 30	September 30	December 31
Fiscal 2004				
Petroleum and natural gas revenue	468,043	744,819	3,866,333	6,218,709
Net income	2,155,183	986,745	920,029	70,516
Net income per share - basic	.22	.08	.04	.00
Net income per share - diluted	.22	.06	.03	.00
Fiscal 2003				
Petroleum and natural gas revenue	692,109	569,384	482,375	538,764
Net income	168,772	135,662	56,078	139,538
Net income per share - basic	.04	.03	.01	.04
Net income per share - diluted	.04	.03	.01	.04

2004 net income in each of the first three quarters was a result of recognizing previously unrecognized tax assets. The income (loss) for each quarter in 2004 before taxes was ($247,940), ($219,227), $174,501, and $273,539 respectively. In the third and fourth quarter of 2004 production and operating expenses were significantly higher than the previous quarters due to the number of workovers and the repair and maintenance required to be performed on the properties purchased during the year. These one time charges amounted to $184,681 and $360,757 in the third and fourth quarters of 2004 respectively. In addition, the majority of property taxes in the amount of $132,128 were recorded in the fourth quarter of 2004.

TRANSACTIONS WITH RELATED PARTIES

All related party transactions are measured at the exchange amount, which is the amount agreed to by the related parties. Management has determined that these amounts approximate fair market value.

a) **Quarry Oil & Gas Ltd.**

Pursuant to an Administration Services Agreement dated July 26, 2001 between Quarry and the Company, Quarry provided management and administrative services to the Company for a fee equal to 10% of cash flow from field operations of the Company plus the re-imbursement of third party costs. During 2003, the Company incurred administrative fees totalling $43,169 under the Administration Services Agreement. The Administrative Services Agreement was terminated on April 1, 2003.

At December 31, 2004, an amount of $nil (2003 - $190,687) was receivable from Quarry in respect of production that was marketed by Quarry on behalf of the Company.

The companies were related by virtue of common directorship and management until July 28, 2003. Subsequent to this date, management and directors resigned from their positions with Quarry such that as at December 31, 2003 the companies were no longer related.

b) **Keantha Holdings Inc.**

Commencing April 1, 2003, the Company's administrative, financial, and management services were performed by parties arranged for by Keantha at a prescribed rate of $11,000 per month. Effective October 1, 2003, this agreement was terminated in favour of the payment by the Company of actual expenses incurred for administrative, financial and management services. The Company also incurred interest expense of $55,191 (2003 - $67,123) to Keantha on the debenture. At December 31, 2004, an amount of $nil (2003 -$16,986) was due to Keantha.

The companies were related by virtue of common directorship and management until July 21, 2004. On that date, management and directors resigned from their positions with the Company.

c) **Avenir Capital Corporation and Avenir Operating Corporation**

The Company is related to these companies by virtue of common directorships. The Company conducts joint operating activities with these companies in its normal course of business. At December 31, 2004, $688,027 (2003 – $nil) was due from these companies.

d) **Other**

Included in accounts receivable at December 31, 2003 is $38,797 receivable from a numbered company controlled by a former director and officer of the Company. Netted against this amount are royalties of $45,532 paid on behalf of the Company by a company controlled by a director and officer of the Company. At July 21, 2004, the companies were no longer related and no amounts were owed at December 31, 2004.

The Company incurred rent expenses to Pelorus Navigations Systems Inc. in the amount of $15,000 (2003 - $6,000). No amount was outstanding at the end of the 2004 (2003 - $6000). The companies were related until July 21, 2004 due to a common director.

During the year, the Company incurred consulting fees for services rendered by companies controlled by officers and directors of the Company in the amount of $29,350 (2003 - $36,125). As at December 31, 2004, the amount owing was $nil (2003 - $4,656).

During the year, professional fees of $366,960 (2003 - $nil) were billed by a firm at which a director is a partner. At December 31, 2004, the amount owing was $210,882 (2003 - $nil).

CONTRACTUAL OBLIGATIONS

Peregrine has contractual obligations relating to the lease of head office space. The minimum annual lease payments are $137,592, expiring in August 2009.

As at December 31, 2004, the Company had entered into the following financial hedging contracts:

Transaction Type	Volume	Contract Price	Expiry
AECO Physical Sales	300 GJ/Day	6.64 Cdn$	31-Oct-07
AECO Physical Sales	450 GJ/Day	6.55 Cdn$	31-Oct-07
AECO Physical Sales	750 GJ/Day	6.54 Cdn$	31-Mar-05
AECO Financial Hedge	300 GJ/Day	7.17 Cdn$	31-Oct-06
WTI Fixed Price Hedges	33 Bbl/Day	30.62 US$	28-Feb-05
WTI Collar	30 Bbl/Day	38.00 - 44.65 US$	31-Oct-07
WTI Puts	30 Bbl/Day	40.00 US$	30-Nov-07

Based on dealer quotes, the unrealized gain on these contracts recognized in earnings for the year ended December 31, 2004 was $465,204.

On March 10, 2005, the Company entered into a financial derivative contract (costless collar) whereby it will receive a minimum US$50/bbl and a minimum US$56/bbl for 250 bbl/day commencing May 1, 2005 and ending April 30, 2006.

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Company's financial statements, which have been prepared in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

The following is a discussion of the critical accounting estimates that are inherent in the preparation of the Company's financial statements and notes thereto.

Reserve estimates

Full cost accounting depends on the estimated proven reserves that are believed to be recoverable from the Company's oil and gas properties. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and economic conditions. All of Peregrine's reserves are evaluated by an independent engineering firm, Sproule Associates Ltd.

Reserve estimates are critical to many of our accounting estimates, including:

- Calculating our unit-of-production depletion and future site restoration rates. Proven reserve estimates are used to determine rates that are applied to each unit-of-production in calculating depletion expense.
- Assessing when necessary, oil and gas assets for possible impairment. Estimated future undiscounted cash flows are determined using proven reserves. The criteria used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data become available, reserve estimates also change, possibly materially impacting net income. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although we make every reasonable effort to ensure that our reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to our reserve estimates can arise from changes in oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

It would take a very significant decrease in our proven reserves to limit our ability to borrow money under our credit facility.

Impairment of petroleum and natural gas properties

The Company reviews its full cost pool for impairment annually. An impairment provision is recorded whenever events or circumstances indicate that the carrying value of the Company's properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and probable petroleum and natural gas reserves, as estimated by the Company on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs may change, and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks, and planned future development and sales, impacts the amount and timing of impairment provisions.

Asset retirement obligation

The asset retirement obligation provision recorded in the consolidated financial statements is based on an estimate for total costs for future site restoration and abandonment of the Company's petroleum and natural gas properties. This estimate is based on management's analysis of production infrastructure, reservoir characteristics and depth, market demand for equipment, currently available procedures, and discussions with construction and engineering consultants. Estimating these future costs requires management to make judgments that are subject to future revisions based on numerous factors, including changing technology, political and regulatory environments.

Income taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. The Company periodically assesses its ability to realize on its future tax assets. If the Company concluded that it is more likely than not that some portion or all of the tax assets will not be realized under accounting standards, the tax asset will be reduced by a valuation allowance.

RECENT CANADIAN ACCOUNTING PRONOUNCEMENTS

Full cost accounting

Effective January 1, 2004, the Company adopted the Canadian Institute of Chartered Accountant's Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"). In applying the new guideline, the recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the sum of its future production of proved reserves and sale of unproved properties. If the carrying value is unrecoverable, the Company would then measure the amount of impairment by comparing the carrying amounts of petroleum and natural gas properties and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the sale of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a credit adjusted risk free rate. Any excess is recorded as a permanent impairment. The adoption of AcG-16 had no effect on the Company's financial statements.

Asset retirement obligation

Effective January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Handbook Section 3110, "Asset Retirement Obligations". The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period in which the liability is incurred, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual, or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. The retroactive accounting impact was as follows:

Balance Sheet as at December 31, 2003	As Reported	Changes	As Restated
Assets			
Property and equipment	$ 2,090,959	$ 362,950	$ 2,453,909
Liabilities and shareholders' equity			
Asset retirement obligation	$ 110,906	$ 385,280	$ 496,186
Retained earnings (also see note 18)	$ 484,475	$ (22,330)	$ 462,145

Statements of Income - increases (decreases) For the period ended December 31, 2003	As Reported	Changes	As Restated
Depletion, depreciation and accretion	$ 470,516	$ 4,131	$ 474,647
Net income impact	$ 642,605	$ (4,131)	$ 638,474
Basic and diluted net income per share	$ 0.16	$ –	$ 0.16

Stock based compensation

Effective January 1, 2004, the Company adopted the fair value method of accounting for stock options, on a retroactive basis, without prior period restatement. In the past, the Company measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the grant date, no compensation cost was recognized on any option issuance. All options vested in 2002 and there were no options granted in 2003.

As a result of the adoption of this policy, the Company has recorded a charge to retained earnings of $74,400 as at January 1, 2004 to reflect the accumulated stock option expense awards made under the plan subsequent to January 1, 2002. Of this amount, $37,200 was recorded as an increase to both share capital and contributed surplus. The estimated fair value of the options issued in 2002 has been determined using a modified Black-Scholes option pricing model assuming no dividends are paid on common shares, a risk-free interest rate of 5.5%, an average life of 5.0 years, weighted average fair value per option of $1.20 and a volatility of 55%.

Financial derivatives

Effective January 1, 2004, the Company has implemented CICA Accounting Guideline ("AcG-13"), "Hedging Relationships", which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. The Company has elected not to apply hedge accounting to its financial hedge contracts. There was no impact upon adoption as there were no hedges in place as at January 1, 2004.

Transportation cost

Effective January 1, 2004, the Company adopted CICA Handbook Section 1100 "Generally Accepted Accounting Principles". As a result, revenue has been presented prior to transportation costs and a separate expense for transportation costs has been presented in the Statement of Income. The adoption of the new policy had no significant impact on the Company's prior period amounts.

BUSINESS RISKS AND OUTLOOK

Business risks

Peregrine's external business risks arise from the uncertainty of crude oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues, and financial and liquidity considerations. Additional risk arises from the production performance of existing properties, the change in regulatory standards and the uncertain results from capital expenditure programs.

Peregrine attempts to minimize pricing uncertainty with a risk management program that encompasses a variety of financial instruments. These include forward sales of oil and natural gas production, put options on both oil and natural gas and costless collars. In general, the Company seeks to use strategies that allow minimum price expectations to be met while preserving most of the Company's exposure to higher prices. This strategy is designed mainly to protect the Company against periods of unusually low commodity prices and by its nature is likely to produce significant hedging losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations, by maintaining adequate insurance, and by adopting appropriate emergency response and employee safety procedures.

Peregrine actively manages the risks of its capital programs by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Finally, Peregrine's capital budget is managed so as to limit capital exposure to any one project or concept to a non-material amount.

Corporate outlook

In 2004, Peregrine consolidated its oil and gas business and strengthened its balance sheet. Peregrine plans to pursue a number of high impact drilling opportunities in 2005 and this, combined with the existing tax pools and non-capital loss carry forward position, should give Peregrine a competitive advantage over other junior oil and gas producers in its ability to generate net income for shareholders and to pursue merger or acquisition opportunities.

CORPORATE

In October 2003, Don J. Brown resigned his position as President and Chief Executive Officer and Al J. Kroontje assumed the position of interim President in addition to his position as Chairman. Concurrently Trevor Penford resigned his position as Chief Financial Officer. On December 31, 2003, concurrent with the closing of Tesoro's $11,000,000 flow through Private Placement, Messrs. Don Brown, Abdel Badwi, Craig Shikaze and Alfred Fischer resigned their positions as directors of the Corporation, and concurrently, Mr. William M. Gallacher and Mr. David E. Butler were appointed to the Board of Directors.

On July 20, 2004, Al J. Kroontje resigned as interm President and Chairman and William M. Gallacher was appointed Chairman. Gary Dundas, Peter Malenica and J.G. (Jeff) Lawson were also appointed to the Board of Directors.

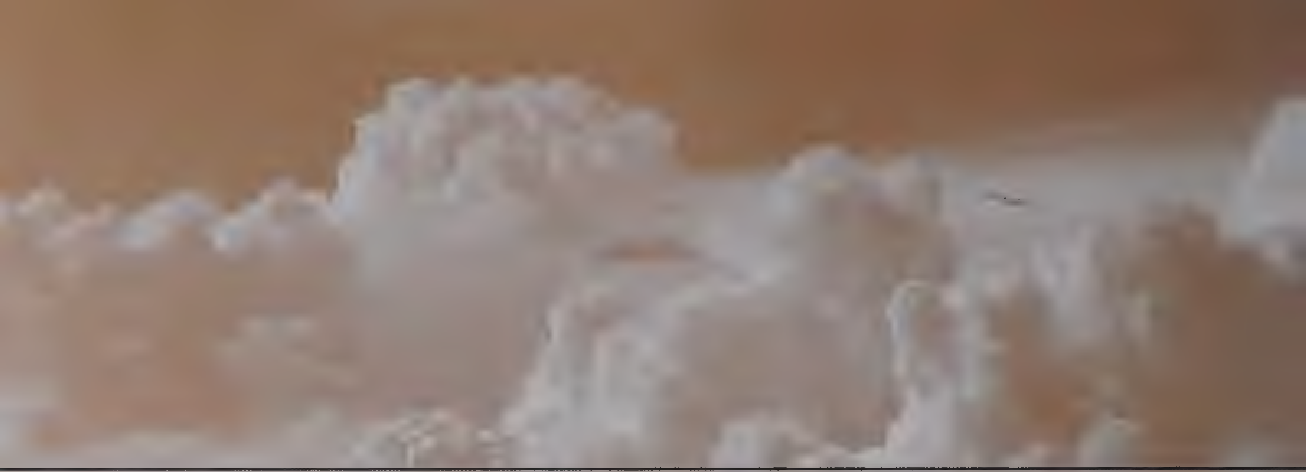
The current officers of the Company are: Peter Malenica – President, William Dawidowski – Vice President of Finance and Chief Financial Officer, Glen Kenealey - Vice President of Engineering, Ed Marcinew – Vice President of Exploration and Robert Van Wielingen – Vice President of Land and Business Development.

For additional information on Peregrine, please go to the company's profile on SEDAR at www.sedar.com.

Submitted on behalf of the Board of Directors by:

Peter Malenica

PETER MALENICA
President and Director



FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF PEREGRINE ENERGY LTD.:

Management is responsible for the preparation of the financial statements in accordance with Canadian generally accepted accounting principles and for ensuring that all other financial and operating information presented in this report is consistent with those financial statements. Management maintains a system of internal controls that is designed to ensure all assets are safeguarded and managed efficiently and to facilitate the preparation of reliable and timely financial information.

Independent auditors, appointed by the shareholders of the Company, have examined the financial statements and the corporate and accounting records in order to express their opinion on the financial statements. The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Audit Committee of the Board of Directors has reviewed these financial statements with management and the auditors and has reported to the Board of Directors. The Board of Directors has approved the financial statements.

PETER MALENICA
President and Director

WILLIAM DAWIDOWSKI
VP Finance and Chief Financial Officer

AUDITOR'S REPORT

TO THE SHAREHOLDERS OF PEREGRINE ENERGY LTD.:

We have audited the balance sheet of Peregrine Energy Ltd. as at December 31, 2004 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The financial statements as at December 31, 2003 and for the year then ended, prior to the adjustments for asset retirement obligations described in note 3 and the adjustments to operating costs described in note 19, were audited by other auditors who expressed an opinion without reservation on those statements in their report dated May 7, 2004. We have audited the adjustments to the 2003 financial statements and in our opinion, such adjustments, in all material respects, are appropriate and have been properly applied.

Ernst & Young LLP

Chartered Accountants
Calgary, Alberta
March 21, 2005

Balance Sheets

As at	December 31, 2004	December 31, 2003
		(Restated (notes 3 and 19)
Assets		
Current assets		
Cash and cash equivalents (note 16)	$ –	$ 11,054,720
Accounts receivable (notes 6, 13 and 14)	**5,877,680**	383,328
Unrealized gain on financial instrument (note 14)	**465,204**	–
Deposits and prepaid expenses	**106,782**	10,545
	6,449,666	11,448,593
Property and equipment (notes 4, 5, and 6)	**82,680,245**	2,453,909
Future income taxes (note 12)	–	1,032,668
Total assets	**$ 89,129,911**	$ 14,935,170
Liabilities		
Current liabilities		
Bank indebtedness	**$ 457,868**	$ –
Accounts payable and accrued liabilities (note 13)	**9,751,057**	1,309,804
Bank operating loan (note 6)	**19,200,000**	275,000
Deferred revenue (note 8)	**1,326,000**	–
	30,734,925	1,584,804
Debenture (note 7)	–	1,000,000
Deferred revenue (note 8)	**663,000**	–
Asset retirement obligations (note 9)	**6,457,539**	496,186
Future income taxes (note 12)	**3,817,271**	–
	$ 41,672,735	$ 3,080,990
Commitments and contingencies (notes 14, 17, and 18)		
Shareholders' equity		
Share capital (note 10)	**42,891,252**	11,739,385
Contributed surplus (note 10)	**408,706**	15,650
Retained earnings	**4,157,218**	99,145
	47,457,176	11,854,180
Total liabilities and shareholders' equity	**$ 89,129,911**	$ 14,935,170

See accompanying notes to the financial statements

Approved on behalf of the Board of Directors:

WILLIAM GALLACHER
Director

GARY DUNDAS
Director

Statements of Income & Retained Earnings

Years ended December 31	2004	2003
		(Restated (notes 3 and 19)
Revenue		
Petroleum and natural gas	$ 11,297,904	$ 2,282,632
Transportation expenses	(27,155)	–
Royalties, net of ARTC	(1,914,871)	(280,384)
Gain on financial instruments (note 14)	299,418	–
	9,655,296	2,002,248
Seismic sale (note 8)	663,000	–
Interest	85,938	–
	10,404,234	2,002,248
Expenses		
Production and operating	3,867,913	797,379
General and administrative (notes 11 and 13)	1,659,261	383,569
Interest and financing expenses (note 13)	390,937	118,919
Depreciation, depletion and accretion	4,505,250	474,647
	10,423,361	1,774,514
Net income (loss) before provision for income tax	(19,127)	227,734
Provision for income tax (note 12)		
Current	106,233	–
Recovery of future income tax	(4,257,834)	(272,316)
	(4,151,601)	(272,316)
Net income	$ 4,132,473	$ 500,050
Retained earnings (Deficit), beginning of year, as reported	99,145	(158,130)
Adoption of asset retirement obligation (note 3)	–	(18,199)
Adjustment for stock based compensation (note 3)	(74,400)	–
Cumulative effect of error adjustment (note 19)	–	(224,576)
As restated	24,745	(400,905)
Retained earnings, end of year	4,157,218	99,145
Net income per share - Basic (note 10)	$ 0.21	$ 0.12
- Diluted (note 10)	$ 0.21	$ 0.12

See accompanying notes to the financial statements

Statements of Cash Flows

Years ended December 31	2004	2003
		(Restated (notes 3 and 19)
Operating activities		
Net Income	$ 4,132,473	$ 500,050
Items not affecting cash:		
Depreciation, depletion and accretion	4,505,250	474,647
Seismic sale (note 8)	(663,000)	–
Recovery of future income taxes	(4,257,834)	(272,316)
Stock based compensation (note 11)	458,706	–
Unrealized financial derivative gain (note 14)	(465,204)	–
	3,710,391	702,381
Changes in non-cash operating working capital (note 15)	(2,774,087)	(62,493)
	936,304	639,888
Investing activities		
Expenditures on properties and equipment	(26,254,388)	(1,225,034)
Corporate acquisition (note 4)	(366,517)	–
Seismic sale	2,652,000	–
Purchase of oil and gas properties (note 5)	(29,498,487)	–
Proceeds on sale of oil and gas properties	6,000	459,700
Changes in non-cash investing working capital (note 15)	4,325,681	42,318
	(49,135,711)	(723,016)
Financing activities		
Bank operating loan advances, net	17,075,000	275,000
Issuance of common shares, net of expenses	20,594,804	9,783,785
Repayment of debenture (note 7)	(370,370)	–
Changes in non-cash financing working capital (note 15)	(612,615)	673,852
	36,686,819	10,732,637
Increase (Decrease) in cash and cash equivalents	(11,512,588)	10,649,509
Cash and cash equivalents, beginning of year	11,054,720	405,211
Cash and cash equivalents (Bank indebtedness), end of year	$ (457,868)	$ 11,054,720

Supplemental disclosure of cash flow information (note 15)

See accompanying notes to the financial statements

Notes to the Financial Statements

For the year ended December 31, 2004 and 2003

1. ORGANIZATION AND NATURE OF THE BUSINESS

Tesoro Energy Ltd. was incorporated on March 30, 2001 as a wholly-owned subsidiary of Quarry Oil & Gas Ltd. ("Quarry"). On July 26, 2001, Tesoro Energy Ltd. acquired oil and gas properties from Quarry in exchange for common shares, debt and cash. Immediately following this purchase, Tesoro Energy Ltd. entered into a business combination with Pentland Firth Ventures Ltd ("Pentland"), a public company whose shares traded on the Toronto Stock Exchange. Under this business combination, which was recorded as a reverse takeover for accounting purposes, Quarry exchanged all its holdings of common shares of Tesoro Energy Ltd. for Pentland common shares totalling 48.8% of Pentland's equity. Pentland then changed its name to Tesoro Energy Corp. On July 21, 2004, Tesoro Energy Corp. and Peregrine Energy Ltd. ("Privateco") amalgamated and continued under the name Peregrine Energy Ltd. The financial statements reflect the historical results of operations for Privateco from the date of amalgamation. The Company is engaged in the exploration, development, acquisition and production of petroleum and natural gas in Western Canada.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of Peregrine Energy Ltd. (the "Company" or "Peregrine") have been prepared by management in accordance with Canadian generally accepted accounting principles. The timely preparation of financial statements requires that management make estimates and assumptions, and use judgement regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts. In the opinion of management, these financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized.

a) Petroleum and natural gas properties and equipment

Capitalized Costs

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method all costs related to the exploration for and development and production of petroleum and natural gas reserves are capitalized in a single Canadian cost centre. Costs include lease acquisition costs, lease rentals on undeveloped land, geological and geophysical expenses, overhead directly related to exploration and development activities, production equipment, and costs of drilling both productive and non-productive wells.

Proceeds from the disposition of properties are normally applied against capitalized costs, except for significant disposals, which change the depletion rate by more than 20% for which a gain or loss is included in income.

Other capital assets are recorded at cost.

Depletion and Depreciation

All costs of acquisition, exploration and development of oil and gas reserves, associated tangible plant and equipment costs (net of salvage value), and estimated costs of future development of proven undeveloped reserves are depleted and depreciated using the unit of production method based upon estimated gross (before royalties) proven petroleum and natural gas reserves as determined using independent engineers. The costs of unproved properties and seismic costs are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. When proven reserves are assigned or the property is considered impaired, the cost of the property, seismic or the amount of the impairment is added to the costs subject to depletion.

Relative volumes of petroleum and natural gas production and reserves are converted to common units at the rate of six thousand cubic feet of natural gas to one barrel of oil.

Depreciation of other capital assets not related to petroleum and natural gas properties and equipment is provided using the declining balance method at rates between 20 and 30 percent.

Impairment

The Company calculates its ceiling test by comparing the carrying value of properties and equipment to the sum of undiscounted cash flows expected to result from the future production of proved reserves and the sale of unproved properties. Cash flows are based on

third party quoted forward prices, adjusted for transportation and quality. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of petroleum and natural gas properties and equipment to an amount equal to the estimated net present value of future cash flows form proved plus probable reserves and the sale of unproved properties. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess is recorded as a permanent impairment.

The carrying value of undeveloped properties and seismic is reviewed periodically and written down to realizable value if impairment is determined.

b) Asset retirement obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and records a corresponding increase in the carrying value of the related long-lived asset. The fair value is determined through a review of engineering studies, industry guidelines, and management's estimate on a site by site basis. The liability is subsequently adjusted for the passage of time, and is recognized as an accretion expense in the statement of earnings. The liability is also adjusted due to revisions in either the timing or the original estimated cash flows associated with the liability. The increase in the carrying value of the asset is amortized using the unit of production method based on estimated gross (before royalties) proven reserves as determined by independent engineers.

c) Joint operations

From time to time, certain petroleum and natural gas activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

d) Revenue recognition

Petroleum and natural gas sales are recognized when commodities are delivered to purchasers.

e) Per common share amounts

Basic net income per share is calculated based upon the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by applying the treasury stock method to the exercise of outstanding stock options and share purchase warrants, except to the extent that the inclusion of these items would be anti-dilutive to the resulting net income per share calculation. This method assumes that proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the year.

f) Future income taxes

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on the difference between the tax basis of the asset or liability and its carrying value on the balance sheet and are measured using substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. Income tax expense for the period is the tax payable for the period and any change during the period in future income tax assets and liabilities. Future income tax assets are only recorded to the extent that realization of those assets is considered to be more likely than not.

g) Cash and cash equivalents

Cash and cash equivalents are defined as cash and short-term deposits with maturities of three months or less at date of purchase. Cash and cash equivalents are stated at cost, which approximates market value.

h) Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as future income taxes and a reduction to share capital when the expenditures are renounced and expenditures are likely to be incurred.

i) Stock-based compensation plan

Under the Company's stock option plan, options to purchase common shares are granted to directors, officers, employees and consultants at current market prices. Options issued by the Company in 2004 are accounted for in accordance with the fair value

method of accounting for stock-based compensation, and as such the cost of the option is charged to earnings on a straight-line basis over the options vesting period with an offsetting amount recorded to contributed surplus. The fair value of the option at the time of the grant is determined using a Black-Scholes option pricing model.

j) Measurement uncertainty

The amount recorded for depletion and depreciation of petroleum and natural gas properties and the ceiling test calculation are based on estimates of gross proven reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effects on the financial statements of changes in such estimates in future years could be significant.

Inherent in the fair value calculation of asset retirement obligations, are numerous assumptions and judgements including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

k) Comparative figures

On July 21, 2004, Tesoro Energy Corp. and Privateco amalgamated and continued under the name Peregrine Energy Ltd. Under the terms of the amalgamation each Tesoro and Privateco shareholder received one share of the amalgamated company for each 20 shares held of the predecessor companies. Accordingly, any reference in these financial statements to shares or dollars per share will have been adjusted by the 1:20 exchange ratio.

l) Financial derivatives

In certain circumstances fixed price commodity contracts or commodity derivative contracts may be used to reduce the Company's exposure to adverse fluctuations in commodity prices to protect future cash flow used to finance the Company's capital expenditure program. Gains and losses relating to commodity derivative contracts which settle via net cash payment and meet hedge criteria are recognized as part of natural gas sales concurrent with the hedge transaction. The Company does not enter into financial instruments for trading or speculative purposes.

The hedging requirements as amended by Accounting Guideline 13, consist of the designation of the instrument as a hedge, the identification of the nature of the risk being hedged and that there is reasonable assurance that the instrument is expected to be an effective hedge throughout its term. In addition, in the case of anticipated transactions, it is also probable that the transaction designated as being hedged will occur. The Company assesses both at the hedge's inception and on an ongoing basis, whether the derivative financial instruments that have been designated as hedges are highly effective in offsetting changes in fair value or cash flows of the hedged items.

Realized and unrealized gains and losses associated with commodity derivative contracts which have been terminated or cease to be effective prior to maturity, are deferred as other current or non–current assets or liabilities on the balance sheet, as appropriate, and recognized in earnings in the period in which the underlying hedge transaction is recognized. In the event a designated hedge item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

The Company has currently elected not to apply hedge accounting to its hedging relationships.

3. CHANGES IN ACCOUNTING POLICIES

Full cost accounting

Effective January 1, 2004, the Company adopted the Canadian Institute of Chartered Accountant's Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"). In applying the new guideline, the recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the sum of its future production of proved reserves and sale of unproved properties. If the carrying value is unrecoverable, the Company would then measure the amount of impairment by comparing the carrying amounts of petroleum and natural gas properties and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the sale of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a credit adjusted risk free rate. Any excess is recorded as a permanent impairment. The adoption of AcG-16 had no effect on the Company's financial statements.

Asset retirement obligation

Effective January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Handbook Section 3110, "Asset Retirement Obligations". The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period in which the liability is incurred, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual, or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. The retroactive accounting impact was as follows:

Balance Sheet as at December 31, 2003	As Reported	Changes	As Restated
Assets			
Property and equipment	$ 2,090,959	$362,950	$ 2,453,909
Liabilities and shareholders' equity			
Asset retirement obligation	$ 110,906	$385,280	$ 496,186
Retained earnings (also see note 19)	$ 484,475	$ (22,330)	$ 462,145

Statements of Income - increases (decreases) For the year December 31, 2003	As Reported	Changes	As Restated
Depletion, depreciation and accretion	$ 470,516	$ 4,131	$ 474,647
Net income impact	$ 642,605	$ (4,131)	$ 638,474
Basic and diluted net income per share	$ 0.16	$ –	$ 0.16

Stock-based compensation

Effective January 1, 2004, the Company adopted the fair value method of accounting for stock options, on a retroactive basis, without prior period restatement. In the past, the Company measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the grant date, no compensation cost was recognized on any option issuance. All options vested in 2002 and there were no options granted in 2003.

As a result of the adoption of this policy, the Company has recorded a charge to retained earnings of $74,400 as at January 1, 2004 to reflect the accumulated stock option expense awards made under the plan subsequent to January 1, 2002. Of this amount, $37,200 was recorded as an increase to both share capital and contributed surplus. The estimated fair value of the options issued in 2002 has been determined using a modified Black-Scholes option pricing model assuming no dividends are paid on common shares, a risk-free interest rate of 5.5%, an average life of 5.0 years, weighted average fair value per option of $1.20 and a volatility of 55%.

Financial derivatives

Effective January 1, 2004, the Company has implemented CICA Accounting Guideline ("AcG-13"), "Hedging Relationships", which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. The Company has elected not to apply hedge accounting to its financial hedge contracts. There was no impact upon adoption as there were no hedges in place as at January 1, 2004.

Transportation costs

Effective January 1, 2004, the Company adopted CICA Handbook Section 1100 "Generally Accepted Accounting Principles". As a result, revenue has been presented prior to transportation costs and a separate expense for transportation costs has been presented in the Statement of Income. The adoption of the new policy had no significant impact on the Company's prior period amounts.

4. BUSINESS COMBINATION

On July 21, 2004, Tesoro amalgamated with Peregrine Energy Ltd ("Privateco") and continued under the name Peregrine Energy Ltd. On the date of the amalgamation, each Tesoro and Privateco shareholder received, in exchange for twenty shares of their respective companies, one share of Peregrine. In addition, 3,000,000 warrants exercisable at $2.00 per share were also issued. As the Tesoro shareholders hold the majority of the issued shares, the amalgamation has been accounted for as an acquisition of Privateco by Tesoro using the purchase method of accounting as follows:

Net Purchase Price	
Common shares issued	$ 14,011,321
Transaction costs	380,980
Cash acquired	(14,463)
	$ 14,377,838
Allocation of purchase price:	
Property and equipment	$ 20,472,900
Future income tax liabilities	(384,681)
Asset retirement obligations	(1,948,697)
Working capital deficiency	(1,911,684)
Debt	(1,850,000)
	$ 14,377,838

5. PROPERTY AND EQUIPMENT

2004	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	$ 87,786,122	$ 5,294,565	$ 82,491,557
Other	205,841	17,153	188,688
	$ 87,991,963	$ 5,311,718	$ 82,680,245

2003	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	$ 3,513,750	$ 1,059,841	$ 2,453,909

Costs associated with unproven properties, excluded from costs subject to depletion for the year, total $20,838,821 (2003 -$1,183,948) and primarily relate to undeveloped lands and related seismic costs. During the year, the Company capitalized $nil (2003 - $12,087) of general and administrative costs related to exploration and development activities, to petroleum and natural gas properties.

In June and September 2004, the Company purchased petroleum and natural gas properties and equipment totalling $29,498,487. In addition, an amount of $7,989,730 has been included in property and equipment to recognize the effect of the asset retirement obligation ($3,490,577) and a future income tax liability ($4,499,153) on these purchases.

The Company has performed an impairment test as of December 31, 2004 using the estimated average price for each of the next five years as determined by the Company's independent reservoir engineers adjusted for differentials specific to the Company's reserves as follows:

	Oil sales price $/bbl (Cdn)	Gas sales price $/mcf (Cdn)	Liquids sales price $/bbl (Cdn)
2005	43.52	6.74	38.82
2006	40.79	6.43	35.11
2007	36.46	5.99	31.26
2008	33.10	5.52	28.18
2009	31.44	5.16	26.71

Each benchmark price increased by an average of two percent thereafter.
There was no impairment as at December 31, 2004.

6. BANK OPERATING LOAN

The Company has a $25 million revolving operating demand loan from a Canadian chartered bank. At December 31, 2004, $19,200,000 was drawn on this facility. In addition the Company has available a non-revolving acquisition/development demand loan of $7,500,000 which had not been drawn upon at December 31, 2004. The revolving demand loan and non-revolving demand loan bear interest at the bank's prime rate of interest plus 0.25% and 0.50%, respectively. The Company may also borrow by way of banker's acceptances, which are subject to a stamping fee. These credit facilities may be reviewed periodically by the bank, with the next review being scheduled on or before April 30, 2005.

These facilities are collateralized by a $40,000,000 floating charge debenture over the Company's major producing petroleum and natural gas reserves and a general assignment of accounts receivable.

The effective interest rate on amounts outstanding under these credit facilities at December 31, 2004 was 4.5% (2003 - 5.5%).

At December 31, 2004, irrevocable standby letters of credit have been issued for a total of $140,000.

At December 31, 2003, the Company had a credit facility with a Canadian chartered bank for a revolving demand loan for a maximum amount of $1,000,000. The facility bore interest at the bank's prime rate of interest plus 1.0% per annum and is collateralized by a $5 million floating charge debenture over all the Company's assets and a general assignment of book debts. As at December 31, 2003, the Company had drawn $275,000 against this facility.

7. DEBENTURE

At December 31, 2003, the Company had a debenture outstanding held by Keantha Holdings Inc (Keantha), a company controlled by former officers and directors of the Company. On July 21, 2004, this debenture was repaid by the issuance of 370,370 common shares and $370,370 in cash. The common shares were issued at $1.70 per share. This debenture, bore an interest rate of 10% per annum payable monthly, and was secured by the Company's petroleum and natural gas properties.

8. DEFERRED REVENUE

In July, 2004, the Company sold the right to access certain of its seismic data for net proceeds of $2,652,000. Under the terms of the agreement further sales of this data to other parties is suspended for two years. Accordingly, revenue is deferred and recognized over the two year period. For the year ended December 31, 2004, $663,000 has been recognized in income.

9. ASSET RETIREMENT OBLIGATION

Balance as at January 1, 2003	$ 495,551
Liabilities incurred	2,124
Liabilities settled	(40,361)
Accretion expense	38,872
Balance as at December 31, 2003	$ 496,186
Liabilities incurred	268,707
Liabilities acquired (notes 4 and 5)	5,439,274
Accretion expense	253,372
Balance as at December 31, 2004	$ 6,457,539

The total future asset retirement obligations were estimated by management based on the Company's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. The undiscounted amount of estimated cash flows required to settle the obligation, adjusted for inflation, is approximately $14,650,000. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 8.5% and an inflation rate of 2%. The expected period until settlement ranges from a minimum of one year to a maximum of twenty-two years.

10. SHARE CAPITAL

Authorized

Common shares - unlimited number without par value

On July 21, 2004, Tesoro Energy Corp. and Privateco amalgamated and continued under the name Peregrine Energy Ltd. Under the terms of the amalgamation each Tesoro and Privateco shareholder received one share of the amalgamated company for each 20 shares held of the predecessor companies. All share related amounts within these financial statements, including per share amounts, number of shares, number of options and warrants outstanding, have been adjusted to reflect the share consolidation.

Issued	**Number**	**Amounts**
Balance - December 31, 2002	4,059,925	$ 2,154,003
Private placement of flow-through common shares (ii)	5,500,000	11,000,000
Tax benefit of flow-though common shares	–	(272,316)
Exercise of stock options	160,000	208,000
Stock based compensation on options exercised	–	52,700
Share issue expenses	–	(1,403,002)
Balance - December 31, 2003	9,719,925	$ 11,739,385
Adoption of stock based compensation (note 3)	–	37,200
Exercise of stock options	90,000	127,000
For services rendered (v)	58,834	100,000
Exercise of agent warrants (iv)	16,253	19,504
Exercise of special warrants (iii)	3,703,704	10,000,000
Private placement of flow-through common shares (i)	3,529,412	12,000,000
Issued upon the business combination (note 4)	12,635,881	14,011,321
Issued upon repayment of the debenture (note 7)	370,370	629,629
Tax benefit of flow-though common shares (i) (ii)	–	(4,245,641)
Stock based compensation on options exercised	–	102,850
Share issue expenses, net of tax of $21,704	–	(1,629,996)
Balance - December 31, 2004	30,124,379	$ 42,891,252

Contributed Surplus	**Amount**
Balance - December 31, 2003	$ 15,650
Adoption of stock based compensation (note 3)	$ 37,200
Stock based compensation	$ 458,706
Exercise of stock options	$ (102,850)
Balance - December 31, 2004	$ 408,706

i) On June 3, 2004, the Company completed a public offering of 3,529,412 flow-through common shares. The expenditure commitment of $12,000,000 was renounced to investors in March 2005, effective December 31, 2004, in accordance with the terms of the flow-through share agreement. The related qualifying expenditure of $12,000,000 must be incurred by December 31, 2005. At December 31, 2004, $3,606,753 of expenditures have been incurred, leaving an additional $8,393,247 to be incurred in 2005.

ii) On December 31, 2003, the Company completed a public offering of 5,500,000 flow-through common shares. The expenditure commitment of $11,000,000 was renounced to investors effective December 31, 2003 in accordance with the terms of the flow-through share agreement. The related qualifying expenditures of $11,000,000 were incurred by December 31, 2004.

iii) In connection with the 2004 private placement of flow-through common shares, the Company issued Special Warrants for the purchase of 3,703,704 common shares of the Company at a price of $2.70 per share. These Special Warrants were exercised on July 21, 2004 for proceeds of $10,000,000.

iv) In connection with the 2002 private placement of flow-through common shares, the Company issued agents' warrants for the purchase of 16,253 common shares of the Company at a price of $1.20 per share ("Agents' Warrants"). These Agents' Warrants were exercised in 2004.

v) The Company issued 58,824 common shares valued at $100,000 for services rendered by Accumen Capital Finance Partners with respect to a financing fee for the December 31, 2003 flow-through share issue.

Warrants

Under the business combination described in Note 4, warrants were issued to acquire 3,000,000 common shares at $2.00 per share. No value was assigned to these warrants. These warrants expire November 30, 2009.

Per share amounts

The weighted average number of common shares outstanding during the year ended December 31, 2004 of 19,388,053 (2003 – 4,144,870) were used to calculate net income per common share. The weighted average fully diluted common shares outstanding for the year ended December 31, 2004 was 19,960,531 (2003 – 4,226,123).

Stock options

The Company has a stock option plan for issuing common shares to directors, officers, employees and consultants based on approval of the Board of Directors and regulatory authorities. The maximum number of common shares issuable under the plan has been established at 10% of the issued and outstanding shares, and the maximum term of the options is ten years. The exercise price of the options is determined using the closing price per share on the last day preceding the date of grant and vest equally over a three year period. The Company has issued stock options to acquire common shares through its stock option plan of which the following are outstanding at December 31, 2004:

	2004 Number of Options	2004 Weighted Average Exercise Price	2003 Number of Options	2003 Weighted Average Exercise Price
Outstanding, beginning of the year	**65,000**	**$ 1.30**	225,000	$ 1.30
Granted	**664,375**	**$ 1.87**	–	$ –
Exercised	**(90,000)**	**$ 1.41**	(160,000)	$ 1.30
Outstanding, end of the year	**639,375**	**$ 1.88**	65,000	$ 1.30

The following table summarizes information about stock options outstanding at December 31, 2004:

Range of exercise options	Number Outstanding	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$1.70 to $2.00	471,875	5.75	$ 1.70	125,000	$ 1.70
$2.01 to $2.40	167,500	4.68	$ 2.37	–	$ –
	639,375	5.47	$ 1.88	125,000	$ 1.70

11. STOCK-BASED COMPENSATION

The fair value of the stock options granted January 4, 2004 by the Company was estimated using the Black-Scholes option pricing model assuming no dividends are paid on common shares, a risk-free interest rate of 4.5%, an average life of 5.0 years, weighted average fair value per option of $3.00 and volatility of 56%. As the options granted vested immediately, the total fair value amount of $300,000 was included in general and administrative expenses.

The fair value of the other stock options granted by the Company in 2004 was estimated using the Black-Scholes option pricing model assuming no dividends are paid on common shares, a risk-free interest rate of 5.5%, an average life of 5.0 years, and volatility of 90%. The fair value of these options is estimated to be $1,119,000. This amount is amortized to expense over the option's vesting period of three years on a straight line basis. For the year ended December 31, 2004, $158,706 was included in general and administrative expenses.

12. INCOME TAXES

The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate to the net income (loss) before income tax as follows:

	2004	2003
Net income (loss) before before provision for income taxes	$ (19,127)	$ 227,734
Statuatory Canadian Corporate tax rate	39.35%	40.62%
Anticipated tax expense (recovery)	(7,526)	76,564
Non-deductible Crown payments	418,184	66,482
Non-deductible interest	26,930	–
Resource allowance	(315,936)	(82,245)
Stock based compensation	(180,501)	–
Rate change	8,569	–
Other	–	10,524
Recognition of tax pools not previously recognized	(4,207,554)	(343,641)
Future income tax recovery	$ (4,257,834)	$ (272,316)
Capital taxes	106,233	–
	$ (4,151,601)	$ (272,316)

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts available for income tax purposes. The components of the Company's future income tax assets and liabilities are as follows:

	2004	2003
Future tax liabilities		
Net book value of capital assets in excess of tax pools	$ (10,110,685)	$ –
Accrued gain on financial instruments	(156,402)	–
Future tax assets		
Tax pools in excess of net book value of capital assets		4,081,303
Deferred revenue	668,702	–
Asset retirement obligation	2,171,025	201,551
Share issue costs	867,290	477,406
Non-capital loss carryforwards	2,742,799	479,962
Net future tax assets (liabilities)	(3,817,271)	5,240,222
Valuation allowance	–	(4,207,554)
Net future tax assets (liabilities)	$ (3,817,271)	$ 1,032,668

The Company has approximately $63,345,000 in tax pools and loss carryforwards which are available for application against future taxable income.

13. RELATED PARTY TRANSACTIONS

All related party transactions are measured at the exchange amount, which is the amount agreed to by the related parties. Management has determined that these amounts approximate fair market value.

a) Quarry Oil & Gas Ltd.

Pursuant to an Administration Services Agreement dated July 26, 2001 between Quarry and the Company, Quarry provided management and administrative services to the Company for a fee equal to 10% of cash flow from field operations of the Company plus the re-imbursement of third party costs. During 2003, the Company incurred administrative fees totalling $43,169 under the Administration Services Agreement. The Administrative Services Agreement was terminated on April 1, 2003.

At December 31, 2004, an amount of $nil (2003 - $190,687) was receivable from Quarry in respect of production that was marketed by Quarry on behalf of the Company.

The companies were related by virtue of common directorship and management until July 28, 2003. Subsequent to this date, management and directors resigned from their positions with Quarry such that as at December 31, 2003, the companies were no longer related.

b) Keantha Holdings Inc.

Commencing April 1, 2003, the Company's administrative, financial, and management services were performed by parties arranged for by Keantha at a prescribed rate of $11,000 per month. Effective October 1, 2003, this agreement was terminated in favour of the payment by the Company of actual expenses incurred for administrative, financial and management services. The Company also

incurred interest expense of $55,191 (2003 - $67,123) to Keantha on the debenture (note 7). At December 31, 2004, an amount of $nil (2003 -$16,986) was due to Keantha.

The companies were related by virtue of common directorship and management until July 20, 2004. On that date management and directors resigned from their positions with the Company.

c) **Avenir Capital Corporation and Avenir Operating Corporation**

The Company is related to these companies by virtue of common directorships. The Company conducts joint operating activities with these companies in its normal course of business. At December 31, 2004, $688,027 (2003 – nil) was due from these companies.

d) **Other**

Included in accounts receivable at December 31, 2003, is $38,797 receivable from a numbered company controlled by a former director and officer of the Company. Netted against this amount are royalties of $45,532 paid on behalf of the Company by a company controlled by a director and officer of the Company. At July 20, 2004, the companies were no longer related and no amounts owed at December 31, 2004.

The Company incurred rent expenses to Pelorus Navigations Systems Inc. in the amount of $15,000 (2003 - $6,000). No amount was outstanding at the end of the 2004 (2003 - $6,000). The companies were related until July 20, 2004 due to a common director.

During the year, the Company incurred consulting fees for services rendered by companies controlled by officers and directors of the Company in the amount of $29,350 (2003 - $36,125). As at December 31, 2004, the amount owing was $nil (2003 - $4,656).

During the year, professional fees of $366,960 (2003 - $nil) were billed by a firm at which a director is a partner. At December 31, 2004, the amount owing was $210,882 (2003 - $nil).

14. FINANCIAL INSTRUMENTS

a) **Fair Value**

The Company has financial instruments consisting of cash and cash equivalents, accounts receivable, deposits, bank indebtedness, accounts payable, bank operating loans and debentures. The carrying value of these instruments approximates fair value unless otherwise stated.

As at December 31, 2004, the Company had entered into the following financial hedging contracts:

Transaction Type	Volume	Contract Price	Expiry
AECO Physical Sales	300 GJ/Day	6.64 Cdn$	31-Oct-07
AECO Physical Sales	450 GJ/Day	6.55 Cdn$	31-Oct-07
AECO Physical Sales	750 GJ/Day	6.54 Cdn$	31-Mar-05
AECO Financial Hedge	300 GJ/Day	7.17 Cdn$	31-Oct-06
WTI Fixed Price Hedges	33 Bbl/Day	30.62 US$	28-Feb-05
WTI Collar	30 Bbl/Day	38.00 - 44.65 US$	31-Oct-07
WTI Puts	30 Bbl/Day	40.00 US$	30-Nov-07

Based on dealer quotes, the unrealized gain on these contracts recognized in income for the year ended December 31, 2004 was $465,204.

b) **Credit Risk**

A substantial portion of the Company's accounts receivable are with entities in the oil and gas industry. The Company generally extends unsecured credit to those companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Company has not previously experienced any material credit losses on the collection of receivables.

The Company is exposed to losses in the event of non-performance by counterparties to financial derivative transactions. The Company minimizes credit risk associated with possible non-performance on these financial instruments by entering into contracts with only investment grade counterparties, limits on exposures to any one counterparty, and monitoring procedures. The Company believes these risks are minimal.

c) **Interest Rate Risk**

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility.

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were comprised of the following:

	2004	2003
Accounts receivable	$ (5,494,352)	$ (115,238)
Deposits and prepaid expenses	(96,237)	(2,106)
Accounts payable and accrued liabilities	8,441,253	771,021
Less working capital deficiency on business acquisition (note 4)	(1,911,685)	–
Net change	$ 938,979	$ 653,677
Net change by activity		
Operating	$ (2,774,087)	$ (62,493)
Investing	4,325,681	42,318
Financing	(612,615)	673,852
Net change	$ 938,979	$ 653,677

Net change by activity

	2004	2003
Cash interest paid	$ 250,372	$ 100,000
Cash taxes paid	$ 5,833	$ –

16. CASH AND CASH EQUIVALENTS

	2004	2003
Cash and cash equivalents is comprised of:		
Cash	$ –	$ 11,185
Short-term investments	–	11,043,535
	$ –	$ 11,054,720

17. CONTINGENCIES

The Company, in the normal course of operations, is subject to a variety of legal and other claims. Management and the Company's legal counsel evaluate all claims on their apparent merits, and accrue management's best estimate of the likely costs to satisfy such claims. At December 31, 2004, there were no claims filed against the Company.

The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their services to the Company to the extent permitted by law. The Company has acquired and maintains liability insurance for its directors and officers.

18. COMMITMENTS

The Company is committed to payments under operating leases for office space as follows:

2005	$ 137,592
2006	$ 137,592
2007	$ 137,592
2008	$ 137,592
2009	$ 91,728
	$ 642,096

19. CORRECTION OF ERRORS IN PRIOR PERIOD FINANCIAL STATEMENTS

Subsequent to the issuance of the financial statements for the year ended December 31, 2003, errors with respect to not recording a liability to two vendors with respect to royalties due and services rendered dating back to April 2001 were discovered. Accordingly, previous period financial statements have been restated to reflect the correct amounts for royalties and production and operating expenses and accounts payable and accrued liabilities.

The following table illustrates the impact of the error to amounts previously reported:

	Previously Reported	Error Correction	As Restated
For the year ended December 31, 2003			
Royalties	$ 238,472	$ 41,912	$ 280,384
Production and operating expenses	$ 700,867	$ 96,512	$ 797,379
Earnings per share - basic and diluted	$ 0.16	$ 0.04	$ 0.12
As at December 31, 2003			
Accounts payable and accrued liabilities	$ 946,804	$ 363,000	$ 1,309,804
Retained earnings			
(after restatement of change in accounting policy note 3)	$ 462,145	$ (363,000)	$ 99,145

20. SUBSEQUENT EVENTS

On March 10, 2005, the Company entered into a financial derivative contract (costless collar) whereby it will receive a minimum US$50/bbl and a maximum US$56/bbl for 250 bbl/day commencing May 1, 2005 and ending April 30, 2006.

Corporate Information

Board of Directors

David E. Butler
Passport Petroleum Ltd.
Calgary, Alberta

Gary Dundas
Avenir Operating Corp.
Calgary, Alberta

William M. Gallacher
Avenir Operating Corp.
Calgary, Alberta

Jeff G. Lawson
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Peter Malenica
Peregrine Energy Ltd.
Calgary, Alberta

Officers

Peter Malenica
President & Director

William Dawidowski
VP Finance & Chief Financial Officer

Glen Kenealey
VP Engineering

Robert E. Van Wielingen
VP Land & Business Development

Edward Marcinew
VP Exploration

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Auditors

Ernst & Young

Bankers

National Bank of Canada

Engineering Consultants

Sproule Associates Ltd.

Registrar & Transfer Agent

Olympia Trust Company of Canada

Legal Counsel

Burnet Duckworth & Palmer LLP

Stock Exchange Listing

Toronto Stock Exchange
Trading symbol: "PEG"

Abbreviations Used

bbls	barrels
bcf	billion cubic feet
bopd	barrel of oil per day
boe	barrels of oil equivalent
	(6 mcf of gas = 1 boe)
boepd	barrel of oil equivalent per day
DCF	discounted cash flow
GJ	gigajoule
$M	$ thousands
mbbls	thousand barrels of oil
mcf	thousand cubic feet
mcfpd	thousand cubic fee per day
mmcf	million cubic feet
mmBTU	million British Thermal Units
NAV	net asset value
NGLs	natural gas liquids
2D	two dimensional
3D	three dimensional
WI	working interest
WTI	West Texas Intermediate

Conversion Factors Used

To convert from	To	Multiply by
thousands of cubic feet	thousands of cubic meters	0.02832
barrels	cubic meters	0.159
mcfe	STB	0.10
feet	meters	0.3049
miles	kilometers	1.61
acres	hectares	0.4047

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